

Co-optimizing enhanced oil recovery and CO₂ storage by simultaneous water and CO₂ injection

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Abstract

This paper presents a numerical simulation study to investigate whether simultaneous water and gas (SWAG) injection can co-optimize CO₂ storage and enhanced oil recovery. Compositional displacements in a three-dimensional, layered reservoir model are modeled to examine different injection scenarios for maximizing oil recovery and CO₂ storage capacity. The effects of various CO₂-water ratios and different miscibility conditions on sweep efficiency, incremental oil recovery and CO₂ storage capacity are investigated. Compositional changes of oil and gas phases, in the presence of mobile water in immiscible, near miscible or miscible SWAG injection are examined. Simulation results show that SWAG injection can enhance oil recovery compared to waterflooding and continuous CO₂ injection by 6 to 21% the original oil in place. The optimum gas fraction in injection fluid increases as miscibility develops. When CO₂ is injected simultaneously with water, 30-60% of injected CO₂ can be stored with optimum injection ratios depending on the miscibility condition. On the contrary, in continuous gas injection, both oil recovery and CO₂ storage capacity increase with miscibility. The simulation results also reveal that, for the reservoir studied, near miscible SWAG injection yields the highest oil recovery and storage efficiency in shortest operating duration.

Keywords: Enhanced oil recovery, Gas injection, SWAG, CO₂ sequestration, Numerical simulation

1. INTRODUCTION

Gas injection has been considered as one of the efficient methods for enhanced oil recovery (EOR), particularly when miscibility between injected gas and oil develops (Orr, 2007; Zhou *et al.*, 2011). Miscible or immiscible hydrocarbon gas injections have been applied successfully in different oil reservoirs. Compared to water injection, gas injection is associated with higher microscopic displacement efficiency due to low interfacial tension (IFT) between oil and gas phases (Shegeft and Zamanzadeh, 2012). IFT becomes zero when miscibility develops and this phenomenon increases oil

recovery in the swept zone. Even if miscibility is not reached fully, mass transfer still occurs between the oil and gas phases, leading to low-IFT near-miscible displacements. Several mass transfer mechanisms can take place depending on the composition of injected gas and oil (Stalkup, 1983; Orr, 2007).

Associated recovery mechanisms of miscible displacement (condensing and vaporizing) cause low residual oil saturation in the swept area, while the residual oil saturation in a waterflooding or immiscible gas drive is still significant. Note that high displacement efficiency in the swept region does not mean high oil recovery. The oil recovery depends on the reservoir volume contacted by the flood (sweep efficiency) which is strongly controlled by the mobility ratio of the injected gas and displaced oil. High mobility ratios of a gas-driven miscible displacement eventually yield low sweep efficiency due to unstable fronts. Sweep efficiency of a miscible displacement can be increased by decreasing the mobility behind the flooding front. This can be achieved by injecting water alternately with miscible gas slug (a.k.a. water-alternate-gas injection or WAG). Injected water reduces the relative permeability of gas and therefore lowers the total mobility (Kulkarni and Rao, 2005; Sohrabi *et al.*, 2005). WAG can also be applied by injecting water and gas simultaneously, which is known as SWAG.

The difference between water and gas densities in SWAG processes provides a sweeping mechanism in which water sweeps hydrocarbons downward while gas sweeps hydrocarbons upward. In an SWAG flood, a gas zone must exist between the miscible slug and water zone to ensure miscible displacement. Flowing water ahead of miscible zone reduces the displacement efficiency, whereas, if the gas zone grows, the volumetric sweep efficiency decreases. Therefore, an optimum gas/water injection ratio is sought to keep the gas zone at a constant volume as the flood progresses (Caudle and Dyes, 1958).

SWAG injections can be done under both miscible and immiscible conditions. However, reservoir conditions might limit the complete miscibility development in a multi-contact miscible (MCM) displacement. In all these processes, the mobile water phase exists near injected gas, therefore in order to design a proper miscible/near miscible gas injection, it is necessary to understand the effect of mobile water saturation on MCM process and mass transfer mechanisms. As a result of specific CO₂ characteristics such as high solubility in oil, low minimum miscibility pressure (MMP) and high swelling factor of oil through contacting with CO₂, CO₂ has been recognized as an efficient injectant in MCM floods (Orr, 2007).

The SWAG method was first tested in the Seelington Field, Texas (Christensen *et al.*, 2001). Pilot tests in the Kuparuk River Field in Alaska demonstrated the feasibility of SWAG injection and confirmed its better control of gas mobility than WAG. The pilot test results showed that the SWAG method improved the incremental recovery over waterflood and WAG by 11% and 4.5-5% original oil in place (OOIP), respectively (Ma *et al.*, 1995). SWAG was also implemented in the Siri Field on the Danish continental shelf (North Sea) which showed more than 6% incremental oil recovery over waterflooding (Quale *et al.*, 2000; Berge *et al.*, 2002). Simultaneous water and CO₂ miscible flood in Joffre Viking Pool in Canada was the best CO₂ conformance compared to WAG and continuous gas injection (CGI) with incremental

oil recovery equal to 14% OOIP at 45% HCPV cumulative CO₂ injection (Stephenson *et al.*, 1993). SWAG-CO₂ miscible flood in the Rangely Field, Colorado also showed an oil recovery of 10% over WAG (Attanucci *et al.*, 1993).

The idea of CO₂ injection is central in geological storage of CO₂, also known as CO₂ sequestration. Several methods have been suggested for controlling CO₂ emissions in the atmosphere, among which the sequestration of CO₂ in subsurface formations seems to be one of the technically feasible options (Bradshaw *et al.*, 2007). Geological CO₂ storage has been studied as an effective sequestration method since 1996 when the first field scale project was commenced in the Sleipner Gas Field, Norway (Haugan, 2005). In this ongoing project, CO₂ is being captured from a high-CO₂ gas stream and injected to a nearby saline formation. Note that the major revenue for this project comes from selling natural gas. For the same reason, EOR projects are currently more attractive for CO₂ geological storage given the favorable oil price. But, more importantly, the oil industry has been applying CO₂ EOR for about four decades, demonstrating its technical and economic feasibility. A successful example of CO₂ sequestration and EOR project is injecting CO₂ captured from the North Dakota coal gasification plant into the Weyburn Oil Field, Canada (Bachu and Shaw, 2003).

Note that, in typical CO₂ EOR projects, CO₂ injection process is designed to minimize the amount of CO₂ injected per barrel of oil produced because the availability and cost of CO₂ are the major elements in the project costs (Kovscek and Wang, 2005). Now that there are environmental concerns about anthropogenic CO₂ emissions in the atmosphere which can potentially introduce carbon credits, more coupled CO₂ EOR and sequestration projects can be seen soon. In these projects, the aim will be to optimize both incremental oil recovery and CO₂ storage under given technical and economical conditions. Thus, new designs are needed for optimizing both oil recovery and CO₂ storage objectives which is known as co-optimization (Kovscek and Cakici, 2005; Ghomian *et al.*, 2008). Benefits from carbon credit may balance the expenses of CO₂ purchase, purification, transportation and compression.

This paper presents a numerical simulation study to investigate the co-optimization of CO₂ sequestration and EOR processes for various SWAG injection designs. A compositional reservoir simulator is used as the reservoir engineering tool to obtain the optimum gas-water injection ratio based on different miscibility conditions. Moreover, compositional changes of gas and oil phases are studied to delineate the effect of the mobile water phase on the miscible front and IFT variations.

2. OBJECTIVE FUNCTION

The aim of a coupled CO₂ EOR and sequestration project is to maximize the net present value of the project by optimizing both incremental oil recovery and the amount of CO₂ storage. Kovscek and Cakici (2005) introduced an objective function (f) to combine dimensionless oil recovery and reservoir utilization as it follows:

$$f = w_1 \frac{N_p}{OIP} + w_2 \frac{V_{CO_2}^R}{V_p^R} \quad (1)$$

where $w_1 + w_2 = 1$ with $0 \leq w_1 \leq 1$, w_1 and w_2 are the weighting factors for oil recovery and CO₂ storage, respectively, N_p is the net oil production and OIP stands for oil in place at the start of CO₂ injection, $V_{CO_2}^R$ is the volume of CO₂ stored in the reservoir and V_p^R is the pore volume of the reservoir. Maximizing this function with respect to the specified set of weights is the objective function for a CO₂ injection project. If the aim is to maximize oil recovery, then $w_1 = 1$. Similarly, if the goal is to maximize CO₂ storage, $w_2 = 1$. Because of various tax systems for CO₂ sequestration in different countries, the weighting factors should be chosen based on the revenue produced by both oil recovery and CO₂ sequestered (Kovscek and Cakici, 2005).

Eq.1 poses some drawbacks. First of all, the volume of CO₂ should not be assumed constant. It varies significantly under different conditions of pressure and temperature of the reservoir and is strongly dependent on whether CO₂ is stored as liquid or gas or dissolved in another fluid. Moreover, Kovscek and Cakici (2005) did not consider geological limitations in the calculation of the available pore volume for CO₂ storage and, instead, used the total pore volume of the reservoir. Therefore, the second term in Eq. 1 should not be an acceptable representation of the CO₂ storage in the reservoir. In order to fill this gap, Jahangiri and Zhang (2010) introduced a new storage factor by using the mass of CO₂ stored in a reservoir $M_{CO_2}^S$ over the total capacity of reservoir for CO₂ storage $M_{CO_2}^T$ which is given by

$$f = w_1 \frac{N_p}{OIP} + w_2 \frac{M_{CO_2}^S}{M_{CO_2}^T} \quad (2)$$

Note that the total capacity of CO₂ in the reservoir is an uncertain parameter for storage estimation. In general, there are many levels of uncertainty within reliable assessments of storage capacity (Bradshaw J, 2008). An extensive multi-disciplinary database is required to develop a meaningful valuation (Allinson *et al.*, 2014).

CO₂ storage capacity in geological formations includes four levels: theoretical, effective, practical and matched storage capacities (Bradshaw, 2008). Theoretical storage capacity which is the total resource and represents the physical limit of what the geological system can accept. Effective storage capacity represents a subset of the theoretical capacity and it considers that part of the theoretical storage capacity which can be physically accessed and meets a range of geological and engineering criteria. Practical storage capacity is a subset of effective storage capacity which satisfies technical, legal and regulatory, infrastructural and economic criteria. Matched storage capacity is a subset of practical storage capacity which considers CO₂ sources with geological storage sites, injectivity and supply rate. The matched capacity to theoretical capacity in an ascending order increases the cost of storage while, from the theoretical to matched capacity, the certainty of storage potential increases (Bradshaw *et al.*, 2007; Bradshaw, 2008; Pingping *et al.*, 2009).

In the case of estimation of the CO₂ storage capacity in oil and gas reservoirs, the fundamental assumption is that CO₂ can refill all the pore volume previously occupied by produced hydrocarbons. This assumption is an upper limit for CO₂ sequestration capacity and is generally valid for reservoirs that are not in hydrodynamic contact with

an aquifer. In reservoirs that are in hydrodynamic contact with an aquifer, water influx decreases the pore space available for CO₂ storage. However, CO₂ dissolution in water enhances storage capacity and CO₂ injection can partially reverse the aquifer influx and make more pore space available for CO₂ storage.

CO₂ storage capacity would be higher due to CO₂ compression under increasing reservoir pressure caused by CO₂ injection (Bachu and Shaw, 2003; Bradshaw, 2008). Bachu and Shaw (2003) showed that water invasion could have the effect of reducing the theoretical storage capacity of depleted reservoirs by 60% on average for oil pools and 28% on average for gas pools, if the reservoir is only allowed to be depressurized back to its initial pressure. Other factors such as reservoir heterogeneity, CO₂ mobility and buoyancy should also be taken into account in determining CO₂ storage capacity.

In this study, we propose a new storage factor for more accurate estimation of the fraction of the CO₂ stored in a reservoir. This new storage factor is the ratio of the amount of CO₂ stored in a reservoir to the amount of injected CO₂ which is given by

$$f = w_1 \frac{N_P}{OIP} + w_2 \frac{M_{CO_2}^S}{M_{CO_2}^I} \quad (3)$$

where $M_{CO_2}^S$ can be found by subtracting the amount of CO₂ produced $M_{CO_2}^P$ from $M_{CO_2}^I$. Hence, Eq. 3 becomes

$$f = w_1 \frac{N_P}{OIP} + w_2 \left(1 - \frac{M_{CO_2}^P}{M_{CO_2}^I}\right) \quad (4)$$

In a CO₂ EOR project, it is straightforward to determine injected and produced amounts of CO₂. According to Eq. 4, the capability of each injection scenario for storing CO₂ gas can be evaluated in addition to oil recovery, while the proficiency of them can be valued based on the total mass of stored CO₂.

In this paper, the goal is to maximize the objective function (Eq. 4) for a period of injection time based on various injection/production scenarios. These injection/production scenarios are defined with respect to the miscibility development in a reservoir. Therefore, effects of the injection process and mass transfer between three mobile phases in reservoirs during a MCM process on oil recovery and CO₂ sequestration are examined. Equal weighting factors, $w_1 = w_2 = 0.5$, for both recovery and storage are used as the base case which states that both aims are equally important. Then, the effect of changing the weighting factors on the results is studied.

3. RESERVOIR AND FLUID DESCRIPTION

A compositional simulator, CMG-GEM, is used in this study to examine the performance of an oil reservoir for SWAG injections. The refined SPE-5 reservoir model is selected for the reservoir model (Killough and Kossack, 1987). The average porosity of the reservoir is 30% which results in a reservoir pore volume of 65.2 MMSTB ($10.36 \times 10^6 \text{ m}^3$). The OOIP is about 51.5 MMSTB ($8.2 \times 10^6 \text{ m}^3$) and the

average initial oil saturation is 80%.

The model contains 3,675 (35×35×3) grid blocks. The x- and y-dimensions of each grid block are 100 ft (30.48 m). One producer and one injector are used for displacing oil with CO₂ and water. The locations of these wells, thickness and permeability of different layers are shown in Figure 1. The two-phase relative permeability data used is shown in Figure 2 taken from the literature previously used for modeling CO₂ injection into the Wasson Field and other CO₂ injection research projects (Hsu *et al.*, 1997; Trivedi and Babadagli, 2005). The Stone II model is used to obtain three-phase relative permeability functions from the two-phase data. The capillary effects and CO₂ solubility in water are neglected in this study. A mixture of 65% C₆ and 35% C₁₀ represents the oil. Based on the results of the WinProp simulator, pure CO₂ has an MMP of 1,785 psi (12,307 kPa) with this oil. The initial reservoir pressure is 3,500 psi (24,132 kPa).

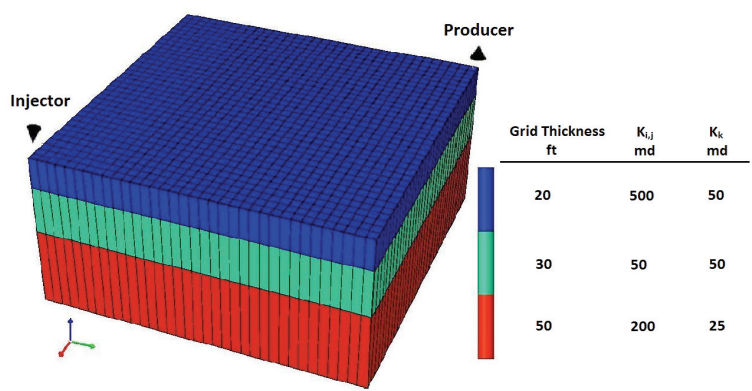


Figure 1. Reservoir model and well locations (Killough and Kossack, 1987).

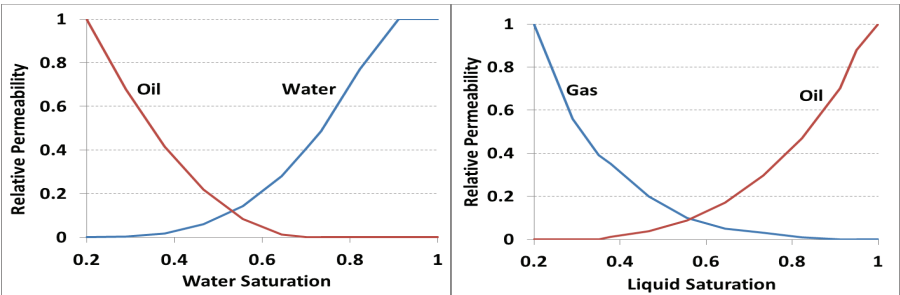


Figure 2. Two-phase relative permeability curves used in the simulations.

4. INJECTION SCENARIOS

A variety of the SWAG injection schemes are tested to co-optimize oil recovery and CO₂ storage. In an injection stream consisting of CO₂ and water, there is a minimum fraction of injected CO₂ that allows for an MCM displacement of oil by injected gas to take place and miscibility is developed in the same way as if only CO₂ were injected with no water present. This CO₂ fraction is defined as the minimum gas fraction (MGF) in a two-phase injection mixture. A miscible SWAG displacement needs to satisfy both the hydrocarbon MMP and CO₂ MGF. Multi-contact miscible gas injection under SWAG injection occurs only at a displacement pressure which is at or above the MMP and a gas fraction in the injected fluid which is higher than the MGF (Orr, 2007; LaForce and Orr, 2009). On the other hand, a high percentage of gas in the injection fluid can raise the mobility ratio and weaken the ability of water to control the front stability. Hence, there is a stability condition which requires a co-optimization of these two injection scenarios.

SWAG injection scenarios can be categorized as immiscible, near miscible and miscible based on the reservoir pressure when injection begins. Since efficient oil recovery highly depends on miscibility, an adequate injection scheme should be designed based on the current reservoir pressure in order to develop miscibility in reservoirs. However, the reservoir pressure may have declined significantly under primary oil production. So, to increase the reservoir pressure to desired levels by SWAG may not be practically possible and, as a result, displacements can be near-miscible or immiscible.

In SWAG injections, the mobility ratio is controlled by an optimized ratio of the injected gas and water. For each injection scheme, a sensitivity analysis should be carried out to determine the optimum SWAG ratio that maximizes a real sweep efficiency. High gas mobility causes front instability and hence viscous fingering if the ratio of CO₂ in the injection fluid is higher than the optimum value. On the other hand, high microscopic displacement efficiency of CO₂ may be reduced by the water phase if the amount of injected CO₂ compared to the water phase is low (Sohrabi *et al.*, 2008; LaForce and Orr, 2009; LaForce and Jessen, 2010). For this reason, complex drive mechanisms under the miscibility development with the presence of mobile water should be studied.

5. RESULTS

In the case study under consideration, oil recovery factor after 1 year of primary production is approximately 5.7% OOIP. The oil production rate becomes very low after this period which suggests applying other production methods for further oil recovery. First, secondary waterflooding (continuous water injection, CWI) is run and the results are used to compare oil recoveries obtained from CGI and SWAG injections. CWI begins after 1 year of primary production and continues for 30 years. Oil recovery from CWI at an injection rate of 8,000 STB/D (1272 m³/d) is 67.8% OOIP in that time. This CWI recovery is used only as a reference. This study assumes gas injection as a secondary recovery mechanism.

In the sections that follow, we present the results of CGI and SWAG injections under different miscibility conditions for various recovery mechanisms. A total

injection rate of 8,000 STB/D (1272 m³/d) is used in all injection scenarios.

5.1. Immiscible case

For the immiscible SWAG injection, the reservoir first produces under primary production. Then the production well operates at a fixed bottom-hole pressure to keep the average reservoir pressure around 1,450 psi (10,000 kPa) which is lower than the MMP (1,785 psi) during injection. Different injection scenarios are run based on various ratios of CO₂ and water injection rates in order to find an optimum gas-water ratio that maximizes the objective function at given reservoir conditions.

The oil recovery profiles shown in Figure 3 indicate that a maximum oil recovery of 74.4% OOIP is obtained at a CO₂-water ratio of 10%. This is higher than recovery factors obtained from CWI and immiscible CGI. The simulation shows that the oil recovery of an immiscible CGI with an injection rate equal to the total gas and water rate in an SWAG injection is about 53% OOIP. In an optimum injection ratio, the displacement front becomes more stable which means that injected gas and water move steadily alongside. In this case, the low mobility of water slows down the flow of gas and thereby increases the displacement efficiency.

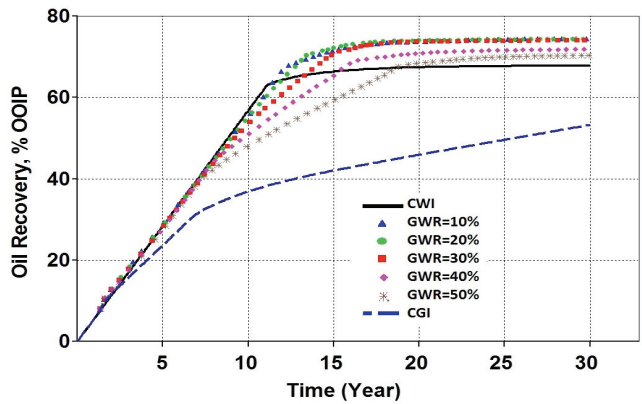


Figure 3. Oil recovery profiles for various gas-water ratios during immiscible CO₂-Water injection.

In the next step of optimizing oil recovery and CO₂ storage, the defined objective function is used. Equal weighting is used for both CO₂ storage and oil recovery. Results in Figure 4 and the summarized data in Table 1 show that the maximum objective function for all cases occurs at CO₂ breakthrough when CO₂ storage efficiency is still 100%. In the immiscible condition, the maximum production life, objective function and oil recovery corresponds to the SWAG injection with GWR=10%, while the minimum CO₂ mass storage is gained by this scenario because the ratio of injected gas in this case is less than the others.

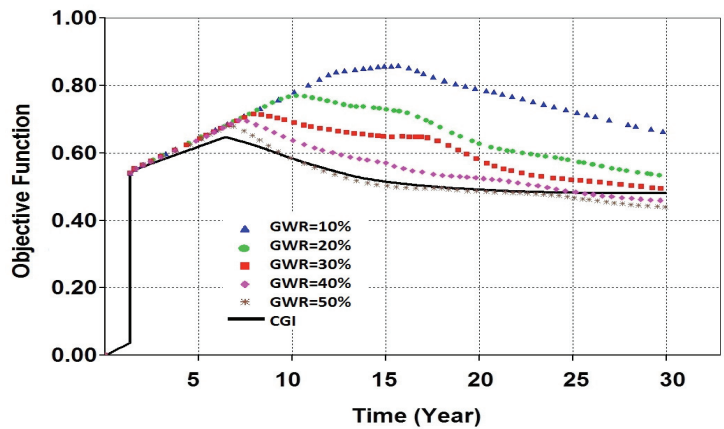


Figure 4. The objective functions for various gas-water ratios during immiscible CO₂-Water injection.

Table 1. EOR and CO₂ storage data of immiscible displacement at the maximum objective function.

Case	Maximum Objective function %	Production life, year	EOR R.F%	CO ₂ efficiency %	CO ₂ mass storage, million tonne
CGI	64	6.5	29	100	0.73
GWR=10%	86	16	72	100	0.27
GWR=20%	77	10	56	100	0.33
GWR=30%	71	8	44	100	0.36
GWR=40%	69	7	39	100	0.40
GWR=50%	68	6	37	100	0.44

The storage efficiency decreases with time after breakthrough (Figure 5). For injection scenarios with lower GWR give later breakthrough because the CO₂ mobility

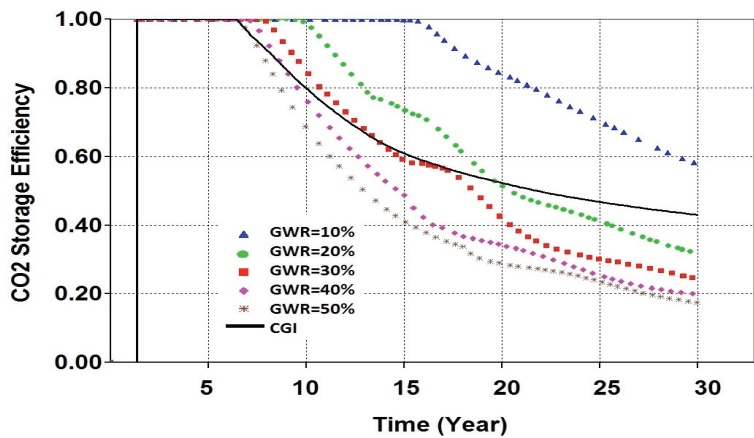


Figure 5. CO₂ storage efficiency for various gas-water ratios during immiscible CO₂-Water injection.

is controlled more efficiently by high water saturations. In the case of GWR=10, about 58% of the injected CO₂ is stored after 30 years. In the immiscible CGI, only 43% of injected CO₂ is stored in the reservoir. Note that CGI has a different profile of storage efficiency. For the given case, only the injection with 10% GWR has better storage efficiency than CGI. In absolute values of CO₂ storage, however, CGI gives the highest and SWAG with 10% GWR the lowest (see Table 1).

For $w_l = 1$, the production continues until the ultimate oil recovery is achieved. In this case, the SWAG with 10% GWR gives the highest oil recovery (Table 1). This is mainly because of a better control of gas mobility.

5.2. Near-miscible case

The near miscible SWAG injection begins after primary production when the reservoir pressure is slightly lower than MMP (around 1,750 psi or 12,065 kPa). The same procedure as in the immiscible injection is applied and different SWAG scenarios with various GWRs are run to determine the optimum one. The simulation results demonstrate that the injection scenario with 30% GWR gives the highest oil recovery after 30 years (Figure 6). Note that all scenarios yield more and less similar ultimate recoveries. The highest ultimate recovery and objective function with $w_l = 1$ is 76% and is obtained from the scenario with 30% GWR.

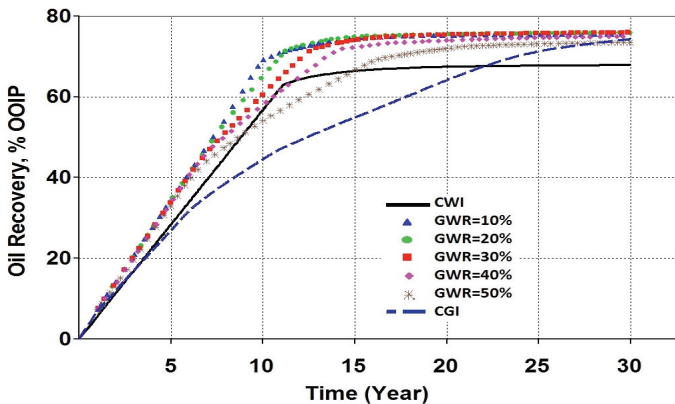


Figure 6. Oil recovery profiles for various gas-water ratios for near miscible CO₂-Water injection.

In SWAG injections, the fraction of injected CO₂ which is stored in the reservoir decreases by increasing the gas mobility in the reservoir as a result of increasing ratio of CO₂ in the injected fluid. Simulations of the near-miscible case indicate that the stored CO₂ fraction at 30% GWR is around 16.6% after 30 years which is lower than the cases with 10% and 20% GWR. However, injecting more CO₂ increases the mass of stored CO₂ which is 3.2×10^5 and 2.1×10^5 tonne for 30% and 10% GWR, respectively. Moreover, as Figure 7 shows, the CO₂ storage fraction of CGI in the near miscible condition is 43% which is almost the same as the immiscible case and more

than the near miscible SWAG cases. According to Figure 8, the objective function for $GWR = 30\%$ is 46% after 30 years. However, the maximum objective function attains after 10.6 years production under the SWAG injection with 10% GWR. The CO_2 storage efficiencies of all cases are close to 100% when the maximum objective function values are obtained, although the stored mass increases significantly by increasing GWRs (Table 2).

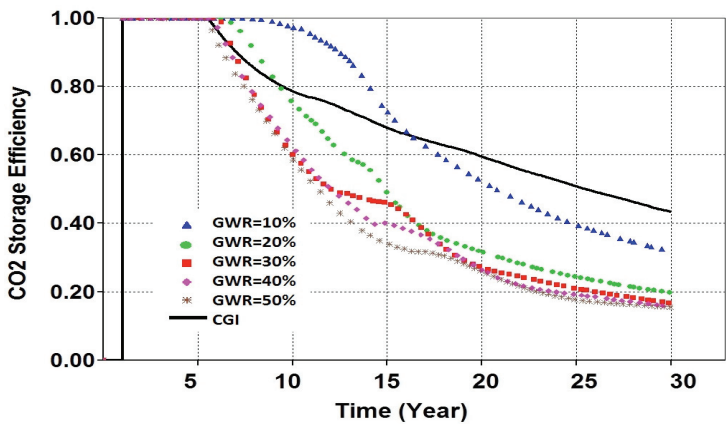


Figure 7. CO_2 storage efficiency for various gas-water ratios for near miscible CO_2 -Water injection.

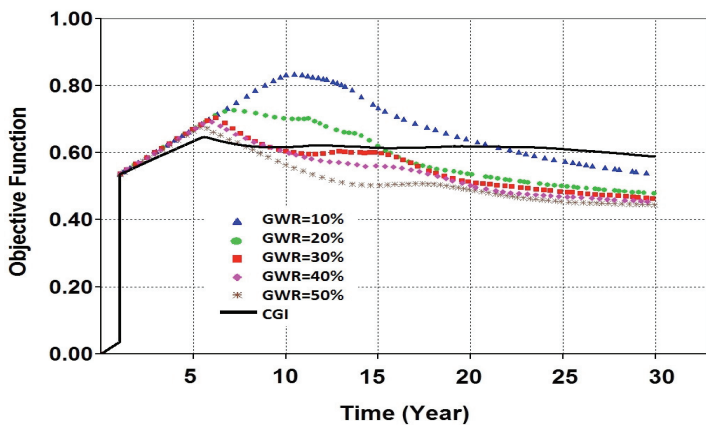


Figure 8. Objective function profiles for various gas-water ratios for near miscible CO_2 -Water injection.

Table 2. EOR and CO₂ storage data of near miscible displacement at the maximum objective function.

Case	Maximum Objective function %	Production life, year	EOR R.F%	CO ₂ efficiency %	CO ₂ mass storage, million tonne
CGI	65	5.7	30	99.3	1.07
GWR=10%	83	10.6	70	97	0.27
GWR=20%	72.6	7.3	49	96	0.35
GWR=30%	70	6.25	41	99	0.44
GWR=40%	69	6	39.5	99.3	0.54
GWR=50%	68	5.5	36.3	99.7	0.63

5.3. Miscible case

The miscible SWAG injection occurs when the reservoir pressure (2,200 psi, 15,168 kPa) is kept higher than the MMP. This pressure is higher than the first contact miscible pressure (1,950 psi, 13,445 kPa) and as a result first contact miscibility can develop in the reservoir during injection.

In a miscible SWAG, the minimum required gas in the injection fluid, which is necessary for having a stable injection front and hence maximum oil recovery, increases as the pressure of the system increases. Figure 9 shows that, in the miscible SWAG injection, the best GWR is 70% which gives an oil recovery of 83.6% OOIP. The objective function for this scenario is 60% after 30 years for $w_1 = w_2 = 0.5$ which is higher than other SWAG scenarios and less than CGI which has a value of 64% (Figure 10). Note that the injection scenario with 10% GWR gives the highest objective function due to delayed gas breakthrough but later declines faster than other scenarios. The CO₂ storage efficiency of the CGI case becomes 36% or 1.88×10^6 tonne as shown in Figure 11.

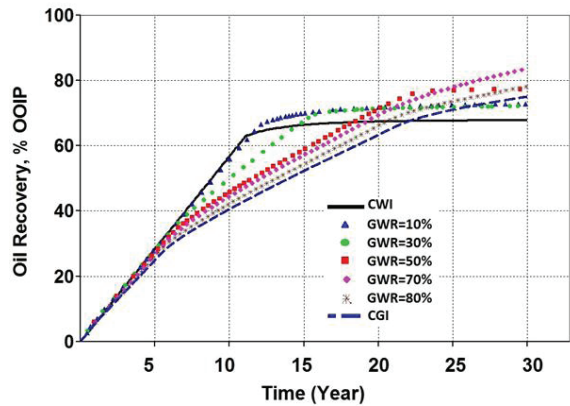


Figure 9. Oil recovery profiles for various gas-water ratios for miscible CO₂-Water injection.

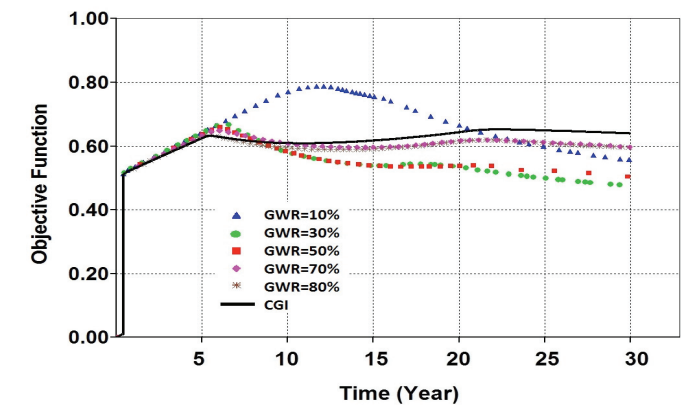


Figure 10. Objective function profiles for various gas-water ratios for miscible CO₂-Water injection.

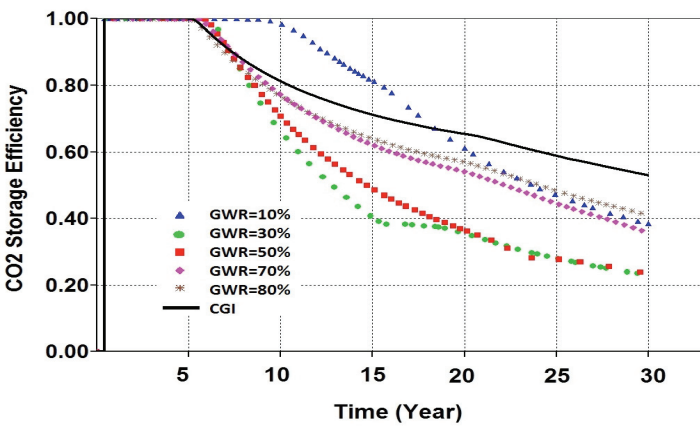


Figure 11. CO₂ storage efficiency for various gas-water ratios for miscible CO₂-Water injection.

Table 3 shows the maximum values of the objective function for the miscible scenarios. The case with GWR = 10% gives the highest value, 79%, after 12 years, even though its CO₂ storage efficiency and stored mass are less than other SWAG cases. The CGI scenario has the longest production life and highest oil recovery and CO₂ stored mass; its objective function is similar to SWAG cases with a high gas-water ratio but with a smaller CO₂ efficiency.

Table 3. EOR and CO₂ storage data of miscible displacement at the maximum objective function.

Case	Maximum Objective function %	Production life, year	EOR R.F%	CO ₂ efficiency %	CO ₂ mass storage, million tonne
CGI	65	22.2	68	63	3.26
GWR=10%	79	12	66	92	0.30
GWR=30%	67	6.3	35	99.7	0.46
GWR=50%	66	6.1	33	99.2	0.72
GWR=60%	66	6.1	32	99	0.84
GWR=70%	65	5.9	31	98.7	0.99
GWR=80%	65	5.4	28	99.2	1.03

6. DISCUSSION

Development of miscibility is important in increasing oil production by means of gas injection. The change of oil and gas compositions in a grid around an injection well is monitored to examine the effect of pressure and miscibility development on mass transfer between the phases. Figures 12-14 show how oil and gas compositions change in immiscible, near miscible and miscible SWAG displacements under OGF condition in the presence of mobile water. All the ternary diagrams for these vaporizing SWAG displacements show similar compositional changes which happen in a gas injection displacement and clarify that the presence of water does not have any effect on the compositional behavior of oil and gas phase if a proper gas fraction is used in the injection phase.

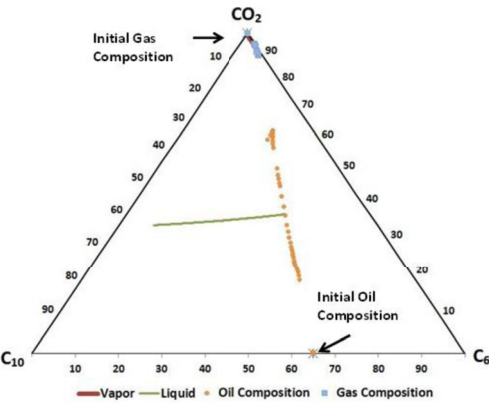


Figure 12. Phase envelope and compositional change during the immiscible displacement.

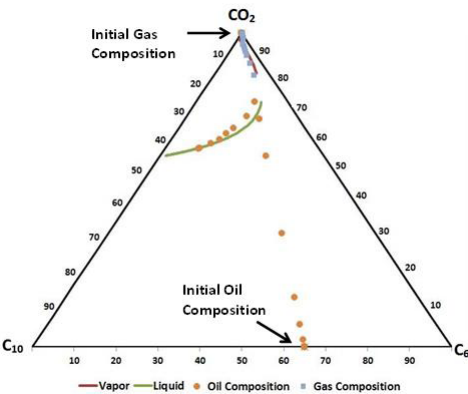


Figure 13. Phase envelope and compositional change during the near miscible displacement.

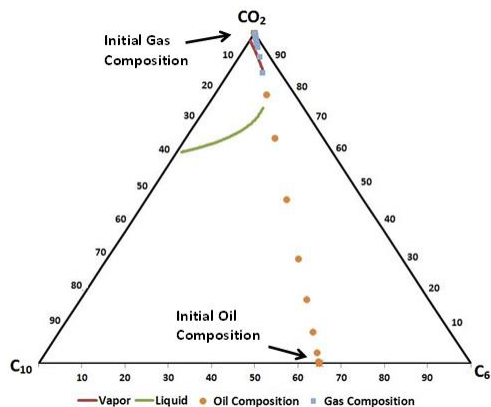


Figure 14. Phase envelope and compositional change during the miscible displacement.

In all injection scenarios, it is seen that OGF is a function of reservoir pressure as phase behavior is strongly affected by pressure. OGF increases as the system pressure rises which could result from the increased volume of CO_2 that partitions into the oleic phase at a high pressure. Moreover, by increasing the system pressure, the MCM can develop in a shorter time which changes the gas viscosity due to vaporization. This increases the fraction of CO_2 that can be injected simultaneously with water where there is still a stable front, as it can be seen in the system with a pressure higher than the MMP. OGF is much greater than the system with a pressure less or near the MMP. LaForce and Orr (2009), using an analytical model, concluded that, at a pressure near or above the MMP, MGF increases by raising the system pressure in a condensing or vaporizing flow model.

In this section, we examine the impact of miscibility on oil recovery and CO_2 storage. Note that the measured OGF in different miscibility conditions strongly depends on the injection rate and production time, because no economic and production constraint is considered. Table 4 shows the ultimate oil recovery of the optimum injection scenarios for all injection processes after 30 years of oil production. As it can be seen, the oil recovery increases more than 9% as the miscibility develops. Similarly, in the case of considering a constant GWR in the injection fluid for all processes, the ultimate oil recovery raises by about 7%. The oil recovery of all optimum SWAG injection cases is higher than the CGI by 9-21%.

Table 4. Comparison of oil recovery after 30 years for immiscible, near miscible and miscible SWAG injection.

Injection Case	Oil Recovery Factor %		
	Optimum Gas Fraction	Constant Gas Fraction (50%)	CGI
Immiscible	74	70.3	53
Near Miscible	76	73.5	74
Miscible	83.6	77.3	75

The fraction of injected CO₂ which is stored in the reservoir and the mass of the CO₂ stored for all injection cases are reported in Table 5. The fraction of stored CO₂ decreases considerably depending on miscibility. This results from mass transfer and solubility of CO₂ in the oleic phase and producing a large amount of CO₂ with oil. In the immiscible case, CO₂ storage efficiency decreases by increasing GWR. In the near miscible condition, the trend of CO₂ storage profile is the same as the immiscible case but with a lower value. While this trend is different in the miscible case, first, the storage coefficient decreases by increasing GWR because of high gas mobility and CO₂ dissolution into the produced oil. This trend continues until the gas fraction in the injected phase is high enough for developing a stable miscible displacement. Higher OGF in the miscible displacement compared to the near miscible increases the chance of CO₂ to occupy void space after depletion. As a result, storage efficiency becomes higher than the near miscible. However, CO₂ production as a miscible component in the oil phase keeps the storage factor less than the immiscible displacement.

Table 5. Fraction and mass of stored CO₂ after 30 years for immiscible, near miscible and miscible gas injection.

Injection Case	Fraction of Stored CO ₂ , %		CGI	Mass of Stored CO ₂ , million tone		
	Optimum Gas Fraction	Constant Gas Fraction (50%)		Optimum Gas Fraction	Constant Gas Fraction (50%)	CGI
Immiscible	58	17.5	43	0.31	0.42	1.53
Near Miscible	23	17.2	51	0.32	0.47	2.04
Miscible	36	23	53	1.88	0.84	3.67

The storage efficiency varies differently under GWR = 50%. In all injection cases, considering another GWR rather than the optimum one means an unstable front and lower CO₂ storage efficiency. In immiscible and near miscible SWAG with GWR of 50% which is higher than OGF, there is not enough volume of water to keep CO₂ in pore space in addition to early breakthrough of CO₂. As a result, CO₂ storage efficiency decreases significantly. In the miscible condition, OGF is higher than 50% and storage coefficient drops because pore space is occupied with water rather than CO₂. Generally, the trend of CO₂ storage efficiency cannot be generalized, because of the various levels of stability changes, different oil characteristics and amount of mass transfer and solubility of CO₂ in oil.

According to the data in Table 5, total stored mass of CO₂ in the reservoir increases when miscibility develops in the reservoir as OGF increases significantly. Moreover, with a constant gas injection rate, the injected mass of CO₂ increases at higher pressures due to higher CO₂ density. Therefore, stored mass of CO₂ rises by miscibility development despite a lower storage efficiency. This result is valid for both OGF and constant GWR scenarios. CO₂ storage efficiency in CGI is different from SWAG as this value increases by miscibility development in the reservoir. This could be because of the existence of only one injection fluid to replace the void space in the reservoir due to oil production. Therefore, oil production and, as a result, CO₂ storage efficiency

increases with miscibility. Furthermore, the total amount of CO₂ injection in CGI is much higher than SWAG, consequently the total stored mass of CO₂ becomes higher, although its storage efficiency is lower in the immiscible cases. This could be a partial result of flowing water phase in pore space, which could lower CO₂ mobility and increase its storage in SWAG process compared to CGI.

The trend of objective function cannot be generalized based on the miscibility or GWR as it is a function of both recovery and CO₂ storage efficiency. High recovery of miscible injection with high storage efficiency of immiscible cases causes a very similar objective function for both miscible and immiscible cases. The near miscible case has the lowest ultimate value because of its lower recovery and storage efficiency compared to miscible and immiscible displacements, respectively. Note that these values can change considerably by changing the weighting factors for oil production and sequestration. According to the data in Tables 1-3 the maximum value of objective function in each case decreases with developing miscibility in the system, which could be caused by the late time effect of high displacement efficiency of a miscible gas injection process. However, at the time of reaching the maximum objective function, the amount of stored CO₂ mass increases with miscibility. The SWAG process with GWR=10% gives the highest objective function values in all cases which has both early high sweep efficiency of water flooding and late CO₂ breakthrough. Even though, the objective function decreases by 7% from the immiscible to miscible case, the near miscible SWAG scenario gives a higher value in a shorter period of time (83% objective function value in 10.6 years). The recovery factor in this condition is 66% which is 8, 10 and 17.6% lower than the ultimate values of immiscible, near miscible and miscible SWAG cases with OGF, respectively.

7. CONCLUSIONS

In this study, a new objective function has been proposed and used to maximize oil recovery and CO₂ storage simultaneously for various SWAG injection schemes. Immiscible, near miscible and miscible SWAG cases with various gas-water ratios have been examined and the results have been compared to the corresponding continuous pure CO₂ injection scenarios.

Compositional simulations show that the SWAG process enhances oil recovery by 6 to 21% OOIP depending on injection scheme. The OGF strongly depends on reservoir pressure and miscibility. On the other hand, miscibility devaluates the CO₂ storage efficiency of SWAG injection from around 60% of the mass of injected CO₂ for an immiscible flood to 36% for a miscible injection. This is because of high mass transfer and solubility of CO₂ in the oil phase at a higher pressure. Therefore, more CO₂ is produced together with a large amount of oil in the miscible displacement.

For the cases studied in this paper, the objective function for SWAG injection is higher than CGI which demonstrates the effectiveness of SWAG as a co-optimization injection scheme for CO₂ EOR and storage at early times. Later, this changes depending on miscibility. For near miscible and miscible cases, CGI gives better results.

The objective functions suggest that 10% GWR is the optimum for the 50% weighting factors for oil recovery and CO₂ storage. Note that different weighting factors which may be set depending on oil and carbon price should lead to different results.

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